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Business Models for Utilities of the Future: Emerging Trends in the Southeast

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ABSTRACT

Growing concerns about clean air and climate change have brought attention to the business models used by electric utilities to promote the deployment of distributed renewables and energy efficiency. To advance the debate on best business practices, this paper analyzes approaches to allocating the costs and benefits of ratepayer-funded energy-efficiency programs, focusing in particular on utilities in the Southeast. Using public data on a southeastern utility, we estimate the impacts of three important features of business models: the recovery of program costs, the treatment of lost contributions to fixed costs, and the provision of utility incentives. Our research indicates that energy-efficiency programs (with or without these business case features) would have only modest impacts on average electricity bills and rates, while significantly reducing electricity costs to participants. Depending on the choice of business model, non-participant utility bills may also decline. Utility earnings are reduced by energy-efficiency programs, but various combinations of business model features largely restore these earnings. The range of options for distributing the costs and benefits of energy-efficiency programs underscores the importance of selecting the right business model. The growing scope and scale of energy-efficiency programs makes this choice increasingly important.

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1. INTRODUCTION

Electric utilities in the Southeast today face an array of challenges. The economic downturn, investments in energy efficiency, and the growth of distributed generation are posing problems for traditional cost of service regulation by producing sluggish demand growth. At the same time, the digital economy is placing greater value on power quality, and growing cyber threats are requiring increased attention to grid security. Finally, concerns over environmental quality and global climate disruption mean that the traditional supply-side options for power generation that have dominated the past several decades of power planning need to be transformed, and demand-side resources merit greater attention because of their increased social value (EPRI, 2014; Kind, 2013).

This confluence of factors is difficult to comport with traditional utility business models. "Demand destruction" imposes upward pressure on utility rates, which can precipitate a downward spiral of utility revenues (Kind, 2013), as consumers react to higher rates by using more energy-efficiency measures and distributed resources like solar and combined heat and power. Demand for utility services declines further, imposing even greater pressure for utilities to increase their rates to compensate for the loss in sales, further eroding demand.

The profits of utility companies are typically a function of how much energy they sell to their customers. Under traditional rate-of-return regulation, electric utility profits are based on the total amount of capital invested in selected asset categories (such as transmission and distribution systems and power plants) and the amount of electricity sold. Accordingly, a utility company's rates are traditionally set on the basis of an estimation of costs of providing service over some period of time (including an allowed rate of return) divided by assumed sales of electricity over that period. If actual sales are less than projected sales, the utility will earn a smaller return on investment and could fail to recover all of its fixed costs.

As a result, traditional ratemaking procedures encourage utilities to increase electricity sales - that is, to increase "throughput" - and discourage utilities from promoting energy efficiency and distributed generation because they reduce throughput (Lesh, 2009; York & Kushler, 2011). For several years, industry groups and think tanks have been challenging these ratemaking practices. In a joint statement in 2014, the Natural Resources Defense Council (NRDC) and Edison Electric Institute (EEI) concluded: "The retail electricity distribution business should not be viewed or regulated as if it were a commodity business dependent on growth in electricity use to keep its owners financially whole".[1]

The range of approaches used by utility companies across the country has engendered a lively debate about the "best practice" business model. We contribute to this debate by quantitatively evaluating the strengths and weaknesses of a range of different business models. Specifically,

[1] *The Energy Daily,* February 13, 42(30): pp. 1-3

we examine alternative business models for compensating and incentivizing utilities to operate and expand energy-efficiency programs. While we focus exclusively on energy efficiency, much of the business model architecture that is examined may also be applicable to the broader range of factors including distributed resources that are simultaneously challenging utilities.

We begin by describing a framework for the business model options building on the "three-legged stool" concept developed over the past decade (NAPEE, 2007).[2] This framework focuses on the recovery of program costs, the recovery of lost contribution to fixed costs, and the provision of utility incentives. We then examine the design of these dimensions in four states across the Southeast (Arkansas, Georgia, North Carolina, and Virginia) and by one national leader, Massachusetts. After describing our research methodology, we present the results of our calibration of the impact of eight business model features: two ways of recovering direct program costs, three approaches to recovering lost contribution to fixed costs, and three methods for incentivizing utility programs.

Because different business model features will be more or less attractive to different stakeholder groups depending on their particular goals, we consider the effect of the features in achieving specific outcomes. We examine the impact of each of the eight business model features on four different goals: to minimize utility bills, maximize utility earnings, maximize the utility's return on equity, and minimize rate impacts. We then define and evaluate the prototypical business model in the Southeast and two alternative approaches to the three-legged stool. Our goal is to illuminate the likely impacts that particular business models might have if implemented in a southeastern state.

2. THREE ESSENTIAL INGREDIENTS OF THE BUSINESS MODEL FOR ENERGY EFFICIENCY IN THE FUTURE

Beginning in the 1970s, electric utilities and their regulators began to develop protocols for evaluating the cost-effectiveness of utility-financed energy-efficiency programs. The result of this effort culminated in detailed program evaluation practice guides including the "California Standard Procedure Manual" and the "International Performance M&V Manual" (IPMVP, 2001; State of California Governor's Office of Planning and Research, 2002). These tests are summarized below, because they have also become imbedded in the debate over alternative business models to compensate utilities for operating energy-efficiency programs. Each of these tests uses a unique combination of costs and benefits as described below. Each test also answers a unique set of questions, as explained by the National Action Plan for Energy Efficiency (NAPEE, 2008).

- The Ratepayer Impact Measure (RIM) test, which identifies the extent to which electric power rates may increase due to the deployment of a given resource option. What is

[2] www.nrdc.org/media/2008/081118.asp

the impact of the energy-efficiency project on the utility's operating margin? Would the project require an increase in rates to reach the same operating margin?

- The Participant Cost Test (PCT), which weighs the costs and benefits to those adopting distributed resource options or participating in utility demand-side management (DSM) programs. Is it worthwhile for the customer to install energy efficiency? Is the customer likely to want to participate in a utility program that promotes energy efficiency?
- The Program Administrator Cost (PAC) test, which weighs the costs and benefits to the utility firm seeking to deploy the given resource option or program. Do total utility costs increase or decrease? What is the total of customer bills required to keep the utility whole (the change in revenue requirement)?
- The Total Resource Cost (TRC) test, which estimates the net benefits of the resource option to both the utility firm and its ratepayers. What is the regional benefit of the energy-efficiency project including the net costs and benefits to the utility and its customers? Are all of the benefits greater than all of the costs (regardless of who pays the costs and who receives the benefits)? Is more or less money required by the region to pay for energy needs?

Over the past decade, the science of program evaluation has progressed rapidly, and consistent procedures have evolved to systematically estimate a program's costs and benefits to different stakeholders. But at the same time, it has become apparent that the rates based on traditional cost of service regulation tend to reward throughput and not the delivery of energy services. As a result, a broader discussion has evolved, focused on "best practices" for compensating utilities for operating energy efficiency programs. Following an extensive stakeholder participation process, the National Action Plan for Energy Efficiency (2007) proposed that best practices must include three components – a three-legged stool (York & Kushler, 2011). The components are: recovery of program costs, decoupling utility profits from electricity sales, and provision of utility performance incentives.

The **recovery of program costs** usually involves adjustments to rates and customer bills. These costs typically include the operating costs of each program, common costs of supporting the programs, and costs of evaluation, measurement and verification (EM&V). These costs can either be expensed or amortized. The focus is on the commission-approved budget for energy efficiency, including both administrative and customer incentive costs. With expensing, 100% of these costs are typically recovered in the year in which they are incurred. With amortization, the commission authorizes the utility to recover program costs over some pre-defined period, including and following the year when they are incurred (perhaps over 3 years, or over the measure lifetime).

In sum, the recovery of program costs is typically done by either expensing the program costs in the same year they are incurred or by amortizing them over multiple years. The years over which the costs are amortized can vary.

Decoupling utility profits from electricity sales is designed to ensure that utilities are indifferent to throughput and will be kept whole when sales decline due to energy efficiency. Over the past decade, this has been accomplished principally with the development of decoupling mechanisms that use periodic rate reconciliations, typically on an annual basis, to compensate for under- or over-collection of revenues to cover fixed costs (NRDC, 2012). According to the definition of decoupling used by NRDC, 16 US states had implemented policies to "decouple" electricity profits from sales as of 2013. This is an increase over the 9 states with decoupling in 2009. Three other states are considering decoupling policies as shown in Figure 1. However, most of the decoupling activities have occurred along the west coast, and in the Northeast and Midwest regions.

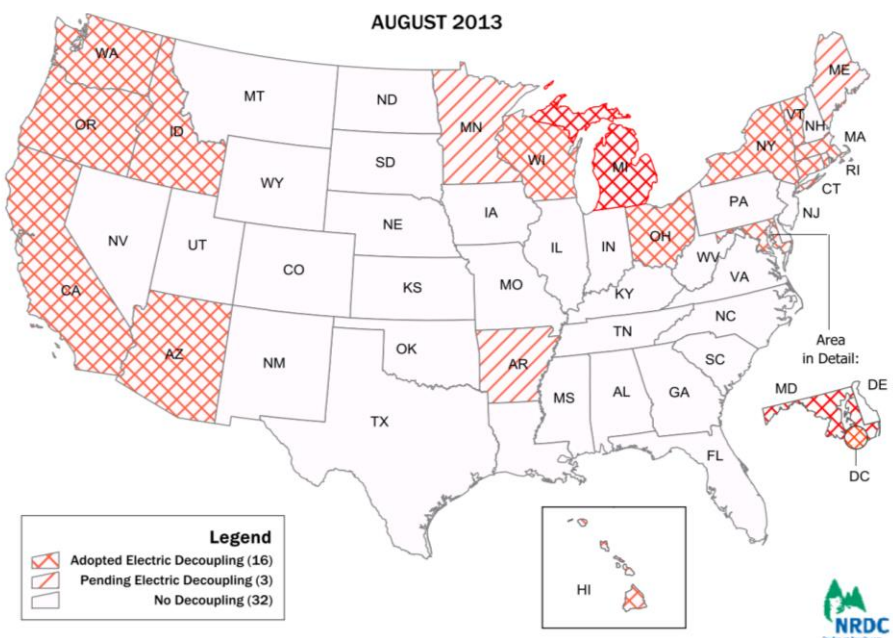

Figure 1. States with Electricity Decoupling
http://www.nrdc.org/energy/decoupling/files/Gas-and-Electric-Decoupling-Maps.pdf

There are a variety of approaches to decoupling (Regulatory Assistance Project, 2011). Most commonly, allowed revenues and rate adjustments are calculated on a revenue-per-customer basis. A per customer decoupling mechanism does a calculation ahead to determine the required rate to collect the allowed revenue per customer and then does a follow up calculation to ensure the previous year earnings fall in the correct range. Decoupling has not been the preferred approach in the Southeast, although the Arkansas Public Service Commission (ARPSC) has invited utilities to propose decoupling mechanisms in upcoming rate cases.[3]

Another approach – the "lost revenue adjustment mechanism" (LRAM) – allows the utility to recover lost contribution to fixed costs based on an estimate of energy savings and associated

[3] ARPSC Docket No. 08-137-U; Order No. 19; dated January 2, 2013

fixed costs. The LRAM takes the expected lost fixed cost and redistributes it over all sales by class. Our research indicates that this approach is being implemented in Arkansas, Kentucky, Louisiana, Mississippi, North Carolina, South Carolina, and Virginia.

Lost contribution to fixed costs can also be remedied by using straight fixed variable rates (SFVR). All fixed costs are recovered through a flat charge, and only variable costs are recovered through a volumetric rate. Our research indicates that this approach is used by some gas utilities in the Southeast but is not used by electric utilities.

In sum, the recovery of lost contributions to fixed costs is accomplished by either converting to a straight fixed variable rate system or through a rate mechanism for lost revenue adjustment or per customer decoupling. Both rate mechanisms simply adjust the volumetric rate in place to ensure a full recovery of all fixed costs given lower sales.

The **provision of utility performance incentives** goes beyond indifference to lost revenues and creates a financial reward for energy efficiency programs. There are three main types of incentive mechanisms. The first is based on a share of the net benefits from approved efficiency programs, as calculated using either the Total Resource Cost test or the Program Administrator Cost test (often called a "shared savings" incentive). The second allows a percentage of program costs keyed to achievement of a fixed energy saving target or a performance goal. The third provides the allowed rate-of-return, sometimes with a bonus amount, on program spending.

Hayes, Nadel, Kushler, & York (2011) concludes that states strongly prefer incentive mechanisms that reward the cost-effective achievement of energy savings and shows that incentive mechanisms based on a share of the benefits from approved efficiency programs are the most common type of program in the U.S. Our research indicates that, in addition to the eleven states shown to practice this form of utility incentive in 2011, including Georgia and Kentucky in the Southeast, a shared savings incentive is being implemented in Arkansas, North Carolina, and South Carolina. In Georgia, North Carolina, and South Carolina, the net benefits are determined by the PAC and in Arkansas and Kentucky, by the TRC. Virginia, by contrast, allows a return on program expenses equal to the utility's return on common equity. Figure 2 combines the findings in 2011 with our subsequent research on the Southeast.

In sum, utility incentives are generally based on a percentage of either program costs or net benefits determined by a standard cost-benefit analysis. Increasingly, recovery is tied to an energy savings target or performance goal. In each case the authorized amount is calculated and then spread over all expected sales by class in order to add it as a rider on the volumetric rate.

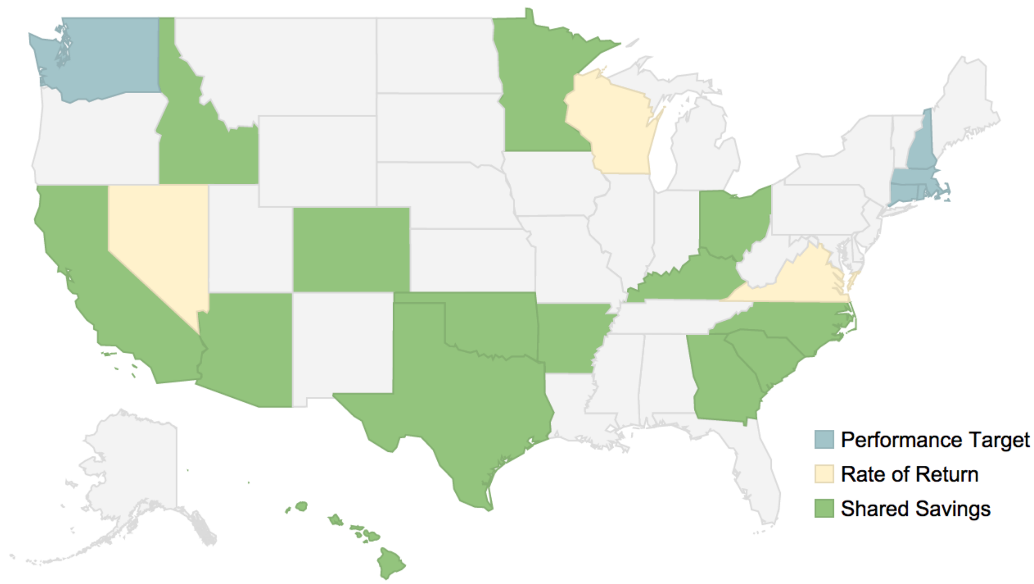

Figure 2. States with Different Types of Program Incentives
(Modified from: Hayes et al., 2011)

Finally, EM&V are critical to the successful implementation of the three-legged stool. In particular, determination of both lost revenues and utility performance depend on calculation of actual energy savings. Initial recovery of lost revenues and incentives is often allowed based on estimated savings, but a "true-up" process generally accounts for the results of EM&V. In all of the states in the Southeast that have implemented the three-legged stool, final recovery depends on net energy savings, not gross savings.

3. OVERVIEW OF THE BUSINESS MODELS USED IN A SELECTION OF STATES

States across the U.S. use different business models to compensate utilities for operating energy-efficiency programs. Because our focus is on identifying best practices applicable to the Southeast, our overview of current business models concentrates on four states in this region with business models that cover all three legs of the stool, using one utility from each state to provide a specific example. These states are: Arkansas (Entergy), Georgia (Georgia Power), North Carolina (Duke Energy Carolinas), and Virginia (Dominion Virginia Power). In addition, we describe the business model used in Massachusetts, the state with the largest utility energy efficiency program expenditures on a per capita basis in 2012, at $78. For comparison purposes, Arkansas spent $17, Georgia spent $3, North Carolina spent $6, and Virginia spent $0.02 (Downs et al., 2013).

3.1 Arkansas

Arkansas has become an energy efficiency rising star in the Southeast, thanks to efforts of the ARPSC to incorporate energy efficiency into the business activities of its major energy utilities.

The ARPSC began requiring its electric utilities to operate energy efficiency programs in 2007.[4] In response, all major electric utilities in Arkansas proposed their own efficiency programs and joined the major natural gas utilities in sponsoring statewide weatherization and education programs. In 2010, the ARPSC increased its efforts behind energy efficiency by establishing energy savings targets.[5] The ARPSC also opened a new docket in 2013 making provisions for the setting of energy savings targets for a three-year planning period beginning in 2015.[6]

In establishing the savings targets approved in 2010, the ARPSC incorporated all three components of energy-efficiency business models. The orders of the Commission included a new provision for recovery of lost revenues that contribute to fixed costs, rules for utility planning that require consideration of efficiency as a resource, and a program performance incentive.

Arkansas utilities are allowed to recover their program costs in an expensed fashion. In addition, they are allowed to recover lost fixed-cost revenues, a value calculated as the estimated savings times a Lost Contribution Rate (LCR),[7] which captures the fixed cost portion of the revenue requirement. These lost revenues are recovered contemporaneously based on deemed savings as part of an annual rider and trued up in the year after they were claimed based on EM&V. The Commission was willing to consider this recovery "only in the context of significant goal setting and the development of robust EM&V." The Commission indicated that "decoupling" might be considered at a later date and has now invited utilities to propose decoupled rate structures.[8]

The program performance incentive established in 2010 is a shared savings incentive based on the TRC test, calculated as 10% of the net benefits for achieving greater than 80% of target savings.[9] It is subject to a cap based on a percentage of the program budget, with the cap increasing as performance against the target improves. The cap has been adjusted in the 2013 docket to align the incentive even more closely with the level of performance.[10] The incentive is not awarded contemporaneously but only after the fact based on EM&V.

3.2 Georgia

An early mover among utility regulators in the southeastern states, the Georgia Public Service Commission (GAPSC) reviews energy efficiency programs through the integrated resource plans (IRPs) filed by regulated electric utilities.[11] The GAPSC has required regulated electric utilities to

[4] ARPSC Docket No. 06-004-R; Orders No. 1, 12, and 18
[5] ARPSC Docket No. 08-137-U; Order No. 15; Dated December 10, 2010
[6] ARPSC Docket No. 13-002-U; Order No. 1; Dated January 4, 2013
[7] ARPSC Docket No. 08-137-U; Order No. 14
[8] ARPSC Docket No. 13-002-U; Order No. 1; Dated January 4, 2013
[9] APSC Docket No. 08-137-U; Order No. 15; Dated December 10, 2010
[10] APSC Docket No. 13-002-U; Order No. 7; Dated September 9, 2013
[11] Official Code of Georgia (O.C.G.A) § 46-3A-2, see also GAPSC Rule 515-3-4

file IRPs every three years since the early 1990s. Since the merging of Savannah Electric & Power Company with Georgia Power in 2006, Georgia Power has been the only regulated electric utility in the state of Georgia.

While the GAPSC has not formally required energy-efficiency programs, the commission has required Georgia Power to explicate any impacts of energy efficiency upon its demand projections.[12] The GAPSC also issued an order making energy efficiency a priority resource in Georgia Power's 2010 IRP hearing. Outside the purview of the GAPSC, cooperatives that are members of the Georgia Electric Membership Corporation and the Tennessee Valley Authority offer energy-efficiency programs.[13]

The GAPSC allows Georgia Power to recover the costs of operating energy-efficiency programs as expenses via a demand-side management rate rider.[14]

The Georgia statute also allows recovery of an "additional sum." Both lost revenues and shared savings are to be considered in arriving at the additional sum, but lost revenues may also be recovered through regular rate cases. Georgia Power files a rate case every three years immediately upon conclusion of the IRP proceedings. To date, the company has chosen to use this rate case process to account for lost revenues resulting from energy-efficiency programs approved in the IRP process. Georgia Power does not include lost revenues in calculating the additional sum, and so it serves as a shared savings incentive.

The shared savings incentive is based on the PAC test. It is conditional on the performance of the energy-efficiency portfolio. If Georgia Power achieves 50% or more of its projected savings, it receives 8.5% of the PAC test net benefits, based on verified net kWh savings, with no cap. If Georgia Power achieves less than 50% of such projected savings, it receives an additional sum of 3% of PAC test net benefits for energy-efficiency measures and 0.5% of PAC test net benefits for demand response measures. If the additional sum exceeds program costs, the portion that exceeds program costs is based on 4% of net benefits.

3.4 Massachusetts

The state of Massachusetts has enjoyed support for energy-efficiency programs from multiple influential actors, including state government, the Department of Public Utilities (DPU), and the utility firms in Massachusetts. In 2008, the Massachusetts legislature set an energy-efficiency resource standard by passing the Green Communities Act. The Green Communities Act established energy efficiency as a utility resource and requires electric utilities to make use of all

[12] O.C.G.A. § 46-3A-1(7), Title 46, Chapter 3A

[13] Information courtesy of ACEEE: http://www.aceee.org/energy-efficiency-sector/state-policy/georgia/183/all/191

[14] O.C.G.A. § 46-3A-9, Title 46, Chapter 3A - Authorizes recovery of program costs, lost revenues, and an incentive

cost-effective energy-efficiency resources before procuring other supply resources (such as power plants). Utilities are required by the Act to submit three-year plans that must meet escalating annual savings targets, reaching 2.6% in 2015. Outside of the Green Communities Act, major electric utilities in Massachusetts have partnered with the Massachusetts Department of Energy Resources to implement the "Mass Save" initiative. Mass Save offers an array of education resources, training resources, incentives, and other services dedicated to promoting energy efficiency.

The MADPU has implemented sweeping and progressive policies toward an alternative business model for its electric utilities' energy-efficiency programs. In 2008, the MADPU began allowing its utilities to propose decoupled rate structures. Several of the utilities regulated by MADPU came forward with decoupled rate proposals in the years following, and MADPU approved these proposals. Not all utilities regulated by MADPU currently offer decoupled rates, however. The decoupled rate structures approved by MADPU allow rates to be adjusted in order for utilities to meet a certain level of revenue authorized during the rate case under certain restrictions. These adjustments are made to recover revenue shortfalls or revenue over-earnings in the prior year. The MADPU restricts the amount of adjustment that can be made to the utilities' rates to less than or equal to 1% of annual revenues (Morgan, 2013).

The MADPU has also implemented thorough and precise incentive mechanisms that reward both savings levels and market transformation efforts. The MADPU offers both a shared savings incentive and a performance target incentive to its utilities. Moreover, the shared savings incentive allows for a certain kind of "double-earning," in which the utility may earn a return on both the level of benefits achieved through its programs and the level of *net* benefits achieved through its programs. The performance thresholds are even more complex, as different metrics are used to measure the performance of each utility program. [15]

3.3 North Carolina

The North Carolina Utilities Commission (NCUC), the North Carolina legislature, and the largest investor-owned utility (IOU) serving North Carolina, Duke Energy Carolinas, have increased efforts toward energy efficiency – both in recent years and in commitments to the future. The North Carolina legislature put its weight behind energy efficiency with the creation of North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) in 2007, and in 2008 the NCUC created the rules necessary for North Carolina utilities to implement the REPS. The REPS requires North Carolina utilities to use efficiency and renewable energy to meet an ever-increasing portion of their prior-year's sales. Despite this favorable policy, the extent to which efficiency could contribute to meeting the requirements of the REPS is limited to 25% of 2012-2018 targets. All told, this means that North Carolina utilities may include energy efficiency

[15] See for example MADPU Docket 14-87; filing by NSTAR electric Dated 06/24/2014. Also see for example MADPU Docket 14-67; filing by Unitil (d/b/a Fitchburg Gas and Electric) Dated 04/01/2014.

equivalent to, at most, 0.75% of their sales between 2008 and 2012; 1.5% of their sales between 2008 and 2015; 2.5% of their sales between 2008 and 2018; and 5% of their sales between 2008 and 2021 in their REPS compliance plans.[16] Electric utilities, including cooperatives, municipally-owned utilities, and IOUs, must file REPS compliance plans with the NCUC on September 1 of every year.[17]

Outside of efforts motivated by legislation, a settlement agreement between Duke Energy Carolinas and environmental organizations has adopted the three-legged stool to compensate the company for performing more energy efficiency. Recovery is through a rider that is trued up annually, based on actual costs and EM&V. Recovery includes all reasonable and prudent costs estimated to be incurred as expenses for approved demand side management and energy efficiency programs.

Under the agreement, NCUC also allows Duke Energy Carolinas to recover Net Lost Revenues, which are net of avoided variable expenses, for 36 months or until the next rate case. In a unique provision, Net Lost Revenues may be offset by Net Found Revenues, as defined in the agreement.[18]

Moreover, the NCUC offers a shared savings incentive mechanism, called the Portfolio Performance Incentive (PPI). The PPI is calculated as 11.5% of the net benefits calculated using the Utility Cost Test (i.e., Program Administrator Cost test). In addition to this percentage of UCT net benefits, the NCUC will allow the company to receive $400,000 for each year that the company's incremental energy savings exceed 1% of the prior year's retail sales. This $400,000 bonus will apply only to the 2014-2018 period.[19]

In addition to these terms for compensation of the utility, another settlement agreement requires Duke Energy Carolinas to set new energy efficiency targets for the 2014 to 2018 period. This agreement came as part of a settlement during the merger of Duke Energy Carolinas and Progress Energy Carolinas in 2011. The merged firm agreed that each of its formerly separate firms would achieve an annual savings target of 1% of the previous year's retail sales beginning in 2015, as well as a cumulative target of 7% by 2018.[20]

3.5 Virginia

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[16] North Carolina utilities are allowed to use energy efficiency to meet up to 40% of their REPS requirements by 2021.

[17] Courtesy of ACEEE: http://www.aceee.org/energy-efficiency-sector/state-policy/north%20carolina/205/all/191.

[18] NCUC Docket No. E-7, Sub 1032; Stipulation Dated 08/19/2013

[19] NCUC Docket No. E-7, Sub 1032; Stipulation Dated 08/19/2013

[20] Settlement can be viewed at http://www.southernenvironment.org/uploads/fck/file/duke-progress-selc-settlement-120811.pdf

The State of Virginia has experienced an array of efforts aimed at fostering energy efficiency through work at both the Virginia legislature and the Virginia State Corporations Commission (SCC). The Virginia legislature articulated a formal goal of reducing its electrical energy consumption by 10% from 2006 levels in the year 2022.[21] A review by the SSC found no evidence against the goal's feasibility.[22] The Virginia legislature amended the Virginia Code in 2009 to articulate provisions for utilities to recover costs of energy-efficiency programs. In its amendment, the legislature also allowed utilities to earn a margin of return on their energy-efficiency program expenses and recover revenues lost due to sales reductions caused by energy-efficiency programs. This margin of return is equal to the general rate of return on common equity,[23] making this incentive of the general class of "return on energy-efficiency investment." Both program costs and this return on energy-efficiency investment may be recovered contemporaneously through an annual rider, subject to scrutiny to assure that they are not used for general marketing and public relations purposes. Program costs include operating costs of each program, common costs of supporting the programs, and EM&V costs.

The Virginia SSC places qualifiers on the recovery of lost contributions to fixed costs. First, lost revenues may not be recovered to the extent that they are offset by incremental off-system sales directly attributable to energy-efficiency programs.[24] Second, the calculation of lost contributions to fixed costs must explicitly consider mitigation of non-fuel reductions in revenue by reductions in variable operating expenses or other factors.[25]

Although the statute provides for recovery of the reduction of fixed-cost revenues due to measured and verified decreases in consumption from approved energy-efficiency programs, the SSC has been stringent in its implementation of those provisions. The SSC's implementation has come in the context of applications by the Dominion Virginia Power for rate riders to recover its costs of energy-efficiency programs under the various categories defined by the Virginia Code. While the SSC approved Dominion's application for recovery of its program costs in 2010,[26] the SSC rejected Dominion's application for recovery of lost revenues, finding that the company could not establish that the projected revenue losses were due to the proposed energy-efficiency program.[27] The SSC staff specifically cited Dominion's lack of Virginia-specific data in the company's calculations of lost revenues as a fatal flaw in Dominion's request.[28] When Dominion applied for lost revenue recovery again in 2011, the SSC rejected the company's request again on the grounds that the company's long-term projections of revenues were

[21] VA Code § 56-590(F)(3) (2009)
[22] VA SCC Case No. PUE-2009-00023
[23] See Virginia Code § 56-685.1
[24] See VA Code § 56-585.1.A.5.c
[25] See VA Code § 56-576
[26] VA SCC Case No. PUE-2009-00081; Order Approving Demand Side Management Programs; Dated March 24, 2010
[27] VA SCC Case No. PUE-2010-00084; Order dated March 22, 2011
[28] VA SCC Case No. PUE-2010-00084, SSC Staff Legal Memorandum dated January 11, 2011

unreasonable.[29] Moreover, when a group of environmental interveners requested that rules for determination of lost revenues be developed, the SSC declined to open a proceeding on that issue. The SSC only held that a "sufficient level of rigor and credibility" must be met before the SSC will approve recovery of lost revenues.[30] To date, no request for recovery has succeeded.

3.6 Summary of Business Model Usage in the Southeast

Based on these five case studies, a review of the literature, and expert consultations, we have identified several general practices used in the Southeast to encourage utilities to invest in energy-efficiency programs. For example, expensing is the most common approach to allowing utilities to recover program costs. The lost revenue adjustment mechanism is the most commonly used way of decoupling utility profits from electricity sales. And shared savings based on net benefits from the Program Administrator Cost test is the most frequently used way of incentivizing performance. Table 1 lists eight business model features and summarizes their usage in the Southeast.

Table 1. Eight Alternative Business Model Features and Their Use in the Southeast

Business Model Feature	Extent of Usage in the Southeast
Recovery of Program Costs	
Amortized for Three Years with a Carrying Cost	Not used by any southeastern electric utilities
Expensed and Recovered Contemporaneously	General practice across the Southeast
Decoupling Utility Profits from Electricity Sales	
Straight Fixed Variable Rate	Used by some gas utilities in the Southeast but not used by any southeastern electric utilities
Lost Revenue Adjustment Mechanism	Arkansas, Kentucky, Louisiana, Mississippi, North Carolina, South Carolina, and Virginia
Per Customer Decoupling	A number of states in the U.S., but none in the Southeast
Provision of Performance Incentives	
Shared Savings based on net benefits from the Program Administrator Cost (PAC) test	Georgia, North Carolina, and South Carolina
Shared Savings based on net benefits from the Total Resource Cost (TRC) test	Arkansas and Kentucky
Return on Program Costs	Virginia

4. METHODOLOGY

Alternative business models for encouraging investments in utility-operated energy-efficiency programs are examined using a simulation approach. First, a "base case" is developed that

[29] VA SCC Case No. PUE-2011-00093; Order dated April 30, 2012
[30] VA Case No. PUE-2012-00100; Order dated April 9, 2013

represents a typical investor-owned utility in the Southeast that has not implemented energy-efficiency programs. Baseline metrics are developed to show the impact of energy-efficiency programs on this utility, if it operates in the absence of any business model features; that is, the utility is assumed to have no recovery of program costs, no decoupling of utility profits from electricity sales, and no provision for utility performance incentives. The simulated utility is assumed to operate both residential and business/commercial energy-efficiency programs. Second, each of the eight features is added one by one to identify their impacts on cost-effectiveness metrics, as well as utility and consumer metrics. Third, we compare and contrast different approaches to the three-legged stool by combining features into the prototypical business model in the Southeast and two alternatives that are under discussion in the Southeast. Further details are provided below.

4.1 The Simulation Model: GT-DSM

GT-DSM is a public domain software tool developed to provide a user-friendly and accessible tool for evaluating the impacts of utility-operated energy-efficiency programs.[31] It integrates methods from existing tools as well as expanding on the level of analysis in certain areas that were identified as lacking by an advisory group. The areas of expansion included fuel cost impacts, capital investment deferrals, and potential impacts of high-consumption participants. The new tool relies strictly on publicly available information for its inputs, runs in MS Excel, and is capable of modeling key impacts to both utility firms and ratepayers. The online version of the tool is illustrated using information on energy-efficiency programs that were proposed by the Georgia Power Company in their 2013 IRP (Georgia Power Company, 2012, 2013). GT-DSM has been used both to develop the base case that represents a typical utility in the Southeast operating in the absence of any of the business model features and to evaluate alternative business models.

The model is laid out in Sectors that cover the impacts of the energy-efficiency program to customers and to the utility. The model also summarizes these impacts in a Cost-Benefit Analysis (CBA) Sector. Within each Sector there are various Modules that cover different categories of impacts from energy-efficiency programs. Modules may also contain various Sub-Modules that are targeted at specific aspects of energy-efficiency program impacts. Users may select which Modules and Sub-Modules to use in order to customize the tool's analysis to meet their evaluation needs.

The Customer Sector focuses on the electricity rate and utility bill and how an energy-efficiency program affects them. To this end, the Customer Sector has two modules: the Rate Impact Module and the Bill Impact Module. In the Customer Sector, residential and commercial programs can be modeled, either as bundled programs (e.g., a set of residential or commercial programs) or as individual programs.

[31] http://cepl.gatech.edu/drupal/node/69

The Utility Sector focuses on the revenues and costs to the utility and how an energy-efficiency program affects those revenues and costs. To this end, the Utility Sector has three modules: the Performance Incentive Module, the Deferred Capital Investment Module, and the Rate Case Module.

The CBA Sector produces estimates of four of the standard cost-effectiveness tests for utility-operated energy-efficiency programs that account for different stakeholder perspectives to energy efficiency.

4.2 Eight Alternative Business Model Features

Table 1 lists eight alternative features of business models that incentivize utility-operated energy-efficiency programs. These same features are quantitatively evaluated in this paper by modeling them in the GT-DSM tool. Their specification is listed below. Their calculations are described in detail in the GT-DSM Users Manual.[32]

- **Recovery of Program Costs**
    - Amortized for Three Years with a Carrying Cost
    - Expensed and Recovered Contemporaneously
- **Decoupling Utility Profits from Electricity Sales**
    - Straight Fixed Variable Rate
    - Lost Revenue Adjustment Mechanism
    - Per Customer Decoupling
- **Provision of Performance Incentives**
    - Shared Savings of 8.5% of net benefits from the PAC test
    - Shared Savings of 8.5% of net benefits from the TRC test
    - Return on Program Costs of 10.0%

GT-DSM allows users to account for free ridership among participants in energy-efficiency programs by including a net-to-gross ratio. In our analysis, we assume this ratio is 0.8 for the calculation of incentives.

As a caveat, the results of the analysis might suggest that the LRAM and Per Customer Decoupling are equivalent; however, this will not always be the case. These two forms of decoupling have nearly identical impacts in our analysis because the underlying economic trends and the performance of the energy-efficiency programs do not deviate from expectations. The LRAM will recover lost revenues to account for losses due to a program. A Per Customer Decoupling mechanism will adjust for additional deviations from the norm. This would include over- and under-collection of revenue based on weather or other unforeseen events impacting energy usage, as well as correcting the authorized amount to be collected based on unforeseen changes in the customer base. It is generally expected that the design of Per Customer

[32] http://cepl.gatech.edu/drupal/node/69

Decoupling would provide a more robust preservation of utility earnings than LRAM. Our analysis is not designed to either support or refute this expectation.

4.3 Potential Business Models

Three combinations of the business model features described above are examined (Table 2).The first combines the features most commonly used in the Southeast as described earlier in our overview of southeastern practices and discourse; it is called the "prototypical business model." The other two combinations are based on subsets of the business model features that are under discussion in the Southeast.

Table 2. Business Model Features of a Prototypical Southeastern Utility

	Recovery of Program Costs	**Decoupling Utility Profits from Electricity Sales**	**Provision of Performance Incentives**
Prototypical Business Model	Expensed	Lost Revenue Adjustment Mechanism	Shared Savings Based on the PAC test
Alternative Business Model 1	Amortized	Straight Fixed Variable Rate	Shared Savings Based on the TRC test
Alternative Business Model 2	Expensed	Per Customer Decoupling	Shared Savings Based on the PAC test

4.4 Evaluation Metrics

Several perspectives are used to examine each business model. First, we use four of the five cost-effectiveness tests described in the "California Standard Procedure Manual" and discussed earlier (State of California Governor's Office of Planning and Research, 2002). Second, we evaluate the impact of alternative business models on utility economics (i.e., including utility earnings and return on equity) and on consumer economics (i.e., electricity rates and the average electricity bills of all customers, participants and non-participants).

4.5 The Utility and Energy-Efficiency Programs Profiled in the Model

The data being used in the GT-DSM tool is based on public filings describing the Georgia Power Company in 2012 and the energy-efficiency programs proposed by the company in its 2013 IRP filing. The Georgia Power Company is the largest utility in Georgia. We do not purport to replicate it in GT-DSM; instead, we use published data describing the Georgia Power Company to create a hypothetical but realistic profile of an investor-owned utility in the Southeast. The "base case" for our analysis is created by revising this profile to describe a utility that has not implemented the energy-efficiency programs proposed in 2013 and also does not have any of the business model features described in this paper.

The profiled utility serves 2.4 million customers, with annual sales of 81.1 TWh and a peak demand of 15.4 GW.[33] The number of customers is expected to grow by 1.0% per year, and sales and demand are expected to grow 1.24% annually. Annual earnings are $1.2 billion based on an 11.25% return on equity from a rate base of $19.5 billion.

Fuel and purchased power costs are collected annually through fuel charges that are adjusted periodically. These costs are assumed to increase by 6.5% per year. Major capital investments are programmed over the next several years to build out new baseload capacity, make environmental retrofits, and improve transmission and distribution facilities.

Average rates are 12 ¢/kWh for residential customers and 8 ¢/kWh for commercial and industrial customers. Residential rates are collected through volumetric charges. The commercial and industrial rate includes a volumetric charge of 6 ¢/kWh, plus a demand charge, equal to $10/kW in the first year. The utility has a peak cost period of 2-7pm on weekdays from June to September. This represents roughly 3.7% of the year. Rate cases are filed every three years.

The capital structure is 54% equity and 46% debt, with a cost of debt of 4.2%. The weighted average cost of capital is 8%.

The profiled utility has programmed energy-efficiency investments for 10 years. It runs two classes of energy efficiency programs: residential and commercial. There is no industrial energy-efficiency program for the profiled utility despite their sales being included with the commercial customers for the analysis.

The residential program is comprised of a collection of end-use specific programs and whole home programs. The end-use specific programs include lighting, air conditioning, and other large home appliances. The whole home programs cover both existing and new homes and generally include insulation and select large appliances. These programs have annual costs of $8.3 million for incentives and $9.8 million for administrative costs. They are set to save 57.8 GWh and 10.2 MW annually for each year of the measure and program lifetimes. The average measure life is assumed to be 10 years. 8% of the residential energy-efficiency program savings occur during the utility's peak period, much more than the roughly 3.7% of the year that occurs during the peak.

The commercial programs target both small and large commercial buildings. The small commercial program includes appliances, lighting, and insulation. The other commercial

[33] This peak demand estimate is calculated in GT-DSM.

programs are from either a long list of prescriptive facility improvements or from a custom built incentives program. These programs have annual costs of $13.7 million for incentives and $5.5 million for administrative costs. They are designed to save 241 GWh and 55.3 MW annually for each year of the measure and program lifetimes. The average measure life is assumed to be 15 years. Since the programs are proposed to deploy measures for 10 years and the measures are assumed to operate for 15 years, our analysis of the impacts of these programs extends for 25 years. 10% of the commercial energy-efficiency program savings are during the utilities peak period, which is more than for the residential program and also much more than the roughly 3.7% of the year that constitutes the peak.

The profiled programs are modest by best practice standards nationally. They are in the mid-range among portfolios of investor-owned utilities in the Southeast. The annual investment represents 0.5% of retail revenues, and the annual energy savings are a little less than 0.4% of sales.

5. RESULTS

The results are presented in three sections. First we describe the utility's performance metrics in the absence of the portfolio of the new residential and commercial energy-efficiency programs (the "base case"). We then examine the performance metrics when these programs are implemented, but no business model features are in place. We call this the baseline comparisons. Second, we describe the utility's performance metrics when implementing the residential and commercial programs in the presence of each of the eight business model features introduced one at a time. The third section describes the utility's performance metrics when the energy-efficiency programs are operated under the prototypical southeastern business model described in Table 2, where all legs of the stool are represented.

5.1 Baseline Comparisons

In the absence of the proposed energy-efficiency programs, the profiled utility has cumulative earnings of $47 billion and a return on equity of 11.46%. The average annual bill of a residential customer is $2,533, while the average bill of a commercial and industrial (C/I) customer is $28,107. The average residential rate is 19 ¢/kWh, and the average C/I rate is 12 ¢/kWh (Table 3). These bills and rates are averaged over 25 years and are not discounted; they therefore are much higher than the average 2013 annual bills ($1,496 and $15,348 for residential and for C/I customers, respectively) and also higher than the 2013 rates (12 ¢/kWh and 8 ¢/kWh for residential and C/I sectors, respectively).

When implemented without applying any business model mechanisms, the residential programs would have less of an impact on utility and customer economics than the commercial programs. Utility earnings over 25 years would drop by $1.2 billion with the residential programs and by $1.8 billion with the commercial programs. The utility's 25-year average ROE would drop by 0.28

percentage points with the residential programs and by 0.42 percentage points with the commercial programs.

On the customer side, average bills would drop by 1.9% for residential customers and by 4.8% for C/I customers. Program participants would benefit from much greater bill savings (7.5% for residential participants and 20.7% for commercial participants). Non-participating households and C/I businesses would both benefit from a small reductions in bills due to rate reductions. Thus, without any elements of the business model being added, the energy-efficiency programs reduce rates by eliminating a greater proportion of more expensive on-peak than off-peak fuel expenditures. The ratio of on- to off-peak savings creates this effect, which is analogous to the demand reduction-induced price effect (DRIPE) seen in ISO-administered electricity markets and in national studies of industrial energy-efficiency programs.[34] With the DRIPE effect, both participants and non-participants can save on their electricity bills when energy-efficiency programs are introduced and utilities are not fully compensated or incentivized.

The benefit-cost tests of the energy-efficiency programs are measured as net present values (NPVs). The Ratepayer Impact Measure (RIM) test shows an NPV loss of approximately $300 million for residential programs and $61 million for commercial programs. These losses occur because bill savings, incentive costs, and program administrative costs would exceed the utility's avoided electric costs. This may seem counterintuitive because, while the RIM test is negative, the average rate does not increase but rather declines. Because neither lost revenue recovery nor program cost recovery has been added, the RIM test result reflects the losses to the utility seen in earnings and ROE rather than increases in rates.[35] The RIM test's negative NPV is due in large part to the lost revenues/bill savings, which are favorable to customers participating in the programs.

The other three benefit-cost tests have net benefit values ranging from $146 to $307 million (for residential programs) and values ranging from $788 to $2,086 million (for commercial programs). These metrics indicate much greater benefits from the commercial programs. The largest benefit-cost test for the residential programs is from the Participant Cost Test (PCT), where the bill savings and incentive payments from the utility exceed the incremental measure cost. For the commercial programs, the largest differential is from the Program Administrator Cost (PAC) test, where the utility's avoided costs exceed the program administrative and incentive costs (Table 3).

[34] For more detail on the DRIPE effect, see Baer, Brown, and Kim (2014) and Synapse Energy Economics, Inc.:
http://www.synapse-energy.com/news/avoided-energy-supply-costs-new-england-2013-report

[35] The RIM test result reflects the costs of energy-efficiency programs that must fall on either the utility, in the form of lost earnings and ROE; or the ratepayers, in the form of increased rates to cover the utility's losses.

Table 3. Impact of Energy Efficiency Programs on Utility Economics in the Absence of any Business model Features

a. Utility and Customer Metrics

	Utility		Customers			
	Cumulative Earnings in $Billions[a]	ROE (25-Year Avg) (%)	Average Energy Bill ($/year)	Participant Energy Bill ($/year)	Non-participant Energy Bill ($/year)	Average Energy Rate (¢/kWh)
Base Case – Utility Without Energy-Efficiency (EE) Programs	47.02	11.46	Residential: 2,533 Commercial: 28,107	NA	NA	Residential: 19.23 Commercial: 12.37
Utility with Residential EE Programs But No Business Model Features	45.84	11.18	Residential: 2,484	2,343	2,533	19.22
Utility with Commercial EE Programs But No Business Model Features	45.22	11.04	Commercial: 26,747	22,293	28,070	12.35

b. Benefit-Cost Tests[b]

($Millions)	Rate Impact Measue Test (RIM)	Total Resource Cost Test (TRC)	Program Administrator Cost Test (PAC)	Participant Cost Test (PCT)
Base Case – Utility Without Energy-Efficiency (EE) Programs	NA	NA	NA	NA
Utility with Residential EE Programs But No Business Model Features	-312	146	161	307
Utility with Commercial EE Programs But No Business Model Features	-61	1,424	2,086	788

[a] Total cumulative earnings over 25 years, not discounted.

[b] Values reported for the benefit-cost tests are the net present values of the net benefits over 25 years with a 7% discount rate for the RIM, TRC, and PAC tests and 10% for the PCT.

NA=not applicable

5.2 Impact of Individual Business Model Features

5.2.1 The Business Model Features Applied to Residential Programs

The baseline metrics change only modestly with the implementation of either of the two mechanisms for recovering residential program costs (Table 4). As expected, reimbursing the utility by expensing rather than amortizing program costs is slightly less beneficial in terms of utility earnings and ROE. Recall that the utility would lose $1.2 billion over 25 years with the residential programs in the absence of any mechanisms. With program cost recovery, the utilities gain earnings of approximately $180 million. The 25-year ROE that averages 11.18% in the base case with residential energy efficiency increases to between 11.22% and 11.23%. Both earnings and ROE would still be less than in the "base case," when these energy-efficiency programs are not implemented.

Both mechanisms for recovering program costs increase bills and rates compared to the utility running programs with no business model features. Both features raise rates from 19.23 to 19.25 ¢/kWh. Average bills are slightly greater under amortized recovery than under expensed recovery. While energy efficiency reduces both participant and non-participant bills, the recovery of program costs erodes some of these savings; non-participants in particular are left with net bill increases under both forms of program cost recovery, but the increment is only $4/year. The CBA tests are unaffected by the recovery of program costs.

In contrast, the mechanisms for decoupling utility profits from electricity sales have a large impact on the evaluation metrics; indeed, they have the largest impact of all three legs of the business model (see Figure 5). Utility earnings and ROE are improved to a similar extent by all three mechanisms, with the LRAM having a slightly more favorable impact than SFVR or Per Customer Decoupling. None of these features returns earnings or ROE to their levels when the utility did not run the energy-efficiency programs; but they raise ROE above the authorized level of 11.25%.

Per Customer Decoupling behaves similarly to the LRAM feature across all the metrics; but Table 4 shows that the SFVR can differentially impact participants and non-participants on their utility bills. The SFVR recovers the same amount of fixed costs from all customers as in the absence of energy-efficiency programs. This minimizes the change in bills for non-participants and focuses the recovery of lost contribution to fixed costs on participants, resulting in larger bill increases for participants than non-participants. As a result, the bills for non-participants are essentially the same as when no business model features were applied. By contrast, the LRAM and Per Customer Decoupling mechanisms spread the lost contribution to fixed costs over the remaining sales, making for similar levels of bill increases across participants and non-participants. Moreover, LRAM and Per Customer Decoupling increase bills for non-participants over what they were in the absence of the residential energy-efficiency program. In sum, the SFVR causes program participants to save much less, while non-participants continue to experience a small energy bill savings, as they did in the absence of this business model feature.

Under the LRAM, SFVR, and Per Customer Decoupling, average bills are modestly penalized – instead of saving 1.9% on bills through energy efficiency without a decoupling mechanism, the average customer saves about 1% when decoupling is added. When either the LRAM or Per Customer Decoupling is implemented, however, non-participants no longer save on their utility bills. For example, non-participants pay energy bills that are 0.77% larger when the residential programs are combined with an LRAM mechanism.[36]

Turning to the benefit-cost tests, the SFVR generates new inputs by reducing lost revenues/bill savings in the RIM test and PCT. The RIM test shows an NPV loss of $47 million relative to the base case, compared to a loss of $312 million without the SFVR. The PCT under the SFVR remains positive but much smaller ($125 million) than under the other business model mechanisms ($307 million) because of smaller bill savings. The LRAM and Per Customer Decoupling do not affect the inputs to the benefit-cost tests.

The evaluation metrics change very little with the implementation of the three mechanisms for providing program incentives. Utility earnings and ROE are virtually the same as when the energy-efficiency programs operate without any business model features. While rates and bills still decrease compared to the "base case", they decrease slightly less as a result of the program incentives; the impact on bills is essentially the same for participants and non-participants. The CBA tests are unaffected by the recovery of program incentives.

Overall, the evaluation metrics change the least with the implementation of the three mechanisms for providing program incentives, and they change the most with the three decoupling mechanisms. The alternative mechanisms for recovery of program costs have similar impacts on utility and customer evaluation metrics. The alternative mechanisms for providing performance incentives are also alike in their impacts. While the three decoupling mechanisms have similar impacts on utility metrics, they have different impacts on the utility bills of program participants and non-participants. Non-participants no longer see utility bill savings with the implementation of the LRAM or Per Customer Decoupling.

[36] It should be noted that variations on how LRAM is implemented may cause deviations in the direction of the results from those presented here. We have calculated lost revenues needed to cover fixed costs based on the full lifetime of measures installed over ten years, for measures still providing savings in that year. In North Carolina and Kentucky, for example, regulators have approved mechanisms that restrict recovery of lost revenues to three years, which affects the total amount of revenue that utilities recover in those cases. Placing a time limit on the LRAM would reduce the cost recovery and would shrink all energy bills though those of non-participants most significantly.

Table 4. Impacts of Business Model Features on Residential Program Economics

a. Utility and Customer Metrics

	Utility		Customers			
	Cumulative Earnings in $Billions[a]	ROE (25-Year Avg) (%)	Average Energy Bill ($/year)	Participant Energy Bill ($/year)	Non-participant Energy Bill ($/year)	Average Energy Rate (¢/kWh)
Utility with residential EE programs but no business model features	45.84	11.18	2,484	2,343	2,533	19.22
(1) Recovery of Program Cost						
Amortized	46.00	11.23	2,489	2,347	2,537	19.25
Expensed	45.97	11.22	2,488	2,346	2,537	19.25
(2) Decoupling Utility Profits from Electricity Sales						
SFVR	46.72	11.38	2,506	2,435	2,532	19.39[b]
LRAM	46.75	11.38	2,507	2,364	2,556	19.39
Per Customer Decoupling	46.72	11.38	2,506	2,363	2,555	19.39
(3) Provision of Performance Incentives						
Shared Savings from the PAC test	45.84	11.18	2,484	2,343	2,533	19.22
Shared Savings from the TRC test	45.84	11.18	2,484	2,343	2,533	19.22
Return on Program Costs	45.85	11.18	2,484	2,343	2,533	19.22

b. Benefit-Cost Tests[c]

($Millions)	Rate Impact Measue test (RIM)	Total Resource Cost test (TRC)	Program Administrator Cost test (PAC)	Participant Cost Test (PCT) in
(1) Recovery of Program Cost				
Amortized	-312	146	161	307
Expensed	-312	146	161	307
(2) Decoupling Utility Profits from Electricity Sales				
SFVR	-47	146	161	125
LRAM	-312	146	161	307
Per Customer Decoupling	-312	146	161	307
(3) Provision of Performance Incentives				
Shared Savings from the PAC test	-312	146	161	307
Shared Savings from the TRC test	-312	146	161	307
Return on Program Costs	-312	146	161	307

[a] Total cumulative earnings over 25 years, not discounted.

[b] Only a portion of this rate comes from volumetric charges, making the actual rate paid 9.55 ¢/kWh.

[c] Values reported for the benefit-cost tests are the net present values of the net benefits over 25 years with a 7% discount rate for the RIM, TRC, and PAC tests and 10% for the PCT.

5.2.2 The Business Model Features Applied to Commercial Programs

The patterns found in the residential assessment are mirrored here, but the effects are larger because the savings here are larger and have more peak-period savings, despite having similar program costs. The two methods of recovering program costs have the same directional impact on utility metrics as they did for the portfolio of residential programs – utility earnings and ROE both rise. Relative to the magnitude of the baseline metrics, the introduction of program cost recovery changes customer metrics very little. Average rates increase only from 12.35 cents to 12.36 cents., and the average bill increases by no more than 0.1% for both program participants and non-participants. Compared to the "base case," with these program cost recovery mechanisms included, participants still cut their electricity bills by nearly one-quarter ($22,308 vs $28,107 per year), while non-participants still benefit from 0.1% off their bills ($28,089 vs $28,107 per year). The CBA tests are unaffected by the program cost recovery.

As with the residential programs, the three decoupling mechanisms have significant impacts on utility metrics. Utility earnings and ROE are improved to a similar extent by all three mechanisms; each mechanism adds approximately $1.4 billion to the utility's earnings and 0.32 percentage points to the utility's 25-year-average ROE (compared to running energy-efficiency programs in the absence of business model features). Earnings and ROE remain below the levels of the "base case," but ROE exceeds the authorized level. Again, we see that, unlike Per Customer Decoupling and the LRAM, the SFVR mechanism has different impacts on the utility bills of program participants and non-participants. Utility bill savings remain strong for participants under all three mechanisms, but non-participants no longer see utility bill savings with the implementation of the LRAM or Per Customer Decoupling ($28,315 vs. $28,107 annual bills).

The provision of performance incentives has small but distinct impacts on the performance metrics. The shared savings incentives that were modeled provide the larger earnings to the utility and costs to the customers compared to the return on program costs. The opposite is true for the residential programs. While both residential and commercial programs spend approximately the same amount of utility funding, the commercial program saves much more electricity, which increases the shared savings but not the incentive based on program costs. As with the residential programs, while rates and bills still decrease compared to the "base case," they increase slightly more as a result of the shared savings incentives based on the PAC test. As with the residential program, the CBA tests are unchanged by the provision of performance incentives.

Table 5. Impacts of Business Model Features on Commercial Program Economics

a. Utility and Customer Metrics

	Utility		Customers (%)			
	Cumulative Earnings in $Billions[a]	ROE (25-Year Avg) (%)	Average Energy Bill ($/year)	Participant Energy Bill ($/year)	Non-participant Energy Bill ($/year)	Average Energy Rate (¢/kWh)
Utility with commercial EE programs but no business model features	45.22	11.04	26,747	22,293	28,070	12.35
(1) Recovery of Program Cost						
Amortized	45.32	11.07	26,766	22,308	28,089	12.36
Expensed	45.32	11.07	26,766	22,308	28,089	12.36
(2) Decoupling Utility Profits from Electricity Sales						
SFVR	46.60	11.36	26,979	23,353	28,070	12.48[b]
LRAM	46.60	11.35	26,980	22,487	28,315	12.48
Per Customer Decoupling	46.60	11.36	26,979	22,487	28,315	12.48
(3) Provision of Performance Incentives						
Shared Savings (PAC)	45.31	11.07	26,764	22,307	28,087	12.36
Shared Savings (TRC)	45.26	11.05	26,754	22,299	28,077	12.35
Return on Program Costs	45.24	11.05	26,750	22,295	28,073	12.35

b. Benefit-Cost Tests[c]

($Millions)	Rate Impact Measue Test (RIM)	Total Resource Cost Test (TRC)	Program Administrator Cost Test (PAC)	Participant Cost Test (PCT)
(1) Recovery of Program Cost				
Amortized	-61	1,424	2,086	788
Expensed	-61	1,424	2,086	788
(2) Decoupling Utility Profits from Electricity Sales				
SFVR	469	1,424	2,086	455
LRAM	-61	1,424	2,086	788
Per Customer Decoupling	-61	1,424	2,086	788
(3) Provision of Performance Incentives				
Shared Savings (PAC)	-61	1,424	2,086	788
Shared Savings (TRC)	-61	1,424	2,086	788
Return on Program Costs	-61	1,424	2,086	788

[a] Total cumulative earnings over 25 years, not discounted.

[b] Only a portion of this rate comes from volumetric charges, making the actual rate paid 9.54 ¢/kWh.

[b] Values reported for the benefit-cost tests are the net present values of the net benefits over 25 years with a 7% discount rate for the RIM, TRC, and PAC tests and 10% for the PCT.

5.3 The Prototypical Southeast Business Model and Variants

Business model features to compensate and incentivize utilities for implementing energy-efficiency programs can be combined in different ways. A preferred approach is emerging in the Southeast, but debate continues about the pros and cons of alternatives. To help focus this discussion, we evaluate the prototypical Southeast business model (defined by expensing program costs, using the lost revenue adjustment mechanism (LRAM), and rewarding performance with shared savings based on net benefits from the Program Administrator Cost (PAC) test) and two alternatives, using the same metrics as used to analyze the individual business model features. The three business models are defined in Table 2.

5.3.1 The Prototypical Southeast Business Model's Impacts on Residential Program Economics

In all of the business models evaluated, combining the three legs of the stool largely restores utilty earnings and ROE to the levels of the "base case." The cumulative loss in earnings of $1.2 billion from implementing the residential programs is reduced to $0.1-0.2 billion. ROE rises to 11.42-11.43%, compared to the "base case" return of 11.46% and the authorized return of 11.25%.

After implementation of the programs and any of the three business models, customer metrics show savings of almost 1% on average bills compared to the "base case." Average rates over 25 years increase about 1.02%. This represents a relatively modest increase in rates over the 25 years (see Figure 3).

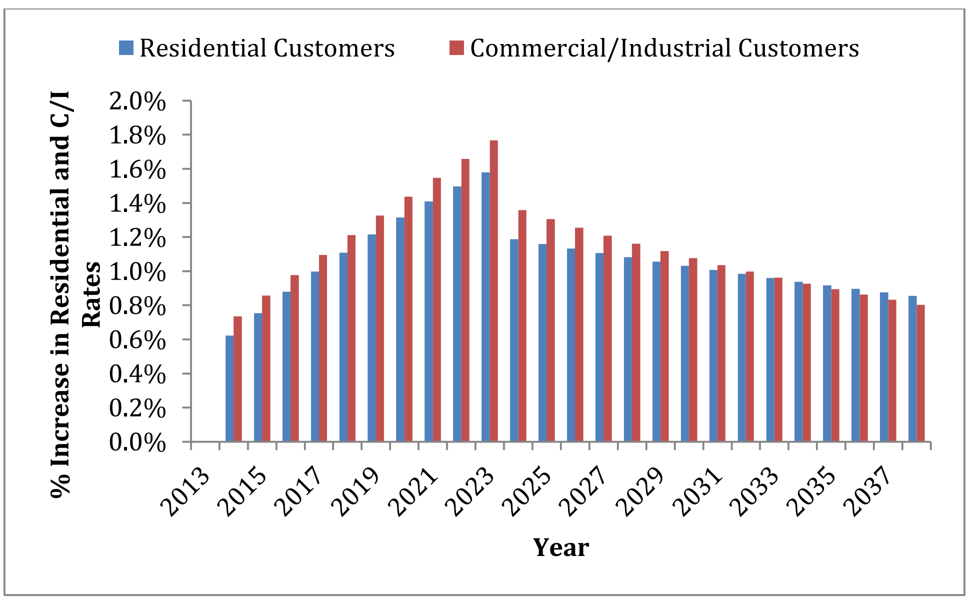

Figure 3: Impact of the Prototypical Business Model Scenario on Residential and C/I Rates
(Note: Compared to "base case" without the energy-efficiency programs)

The three business models, however, distribute the costs and benefits of energy efficiency between utilities, participants, and non-participants in different ways. The prototypical model and the two alternative models all recover utility earnings and ROE through increases in household energy bills and rates. The prototypical business model and Alternative Model 2, which employs Per Customer Decoupling, place a smaller portion of the annual energy bill increases on participating customers than does Alternative Model 1, which uses the straight fixed variable approach (SFVR). The benefit-cost tests for the prototypical business model and Alternative Model 2 are both indistinguishable from the benefit-cost tests with the residential energy-efficiency programs in the absence of any business model features. The benefit-cost tests for Alternative Business Model 1 show distinct impacts. By reducing bill savings, the SFVR feature decreases the PCT net benefit, and it decreases the net loss of the RIM test value by reducing lost revenues.

Table 6. Impact of the Business Models on Residential Program Economics

a. Utility and Customer Metrics

	Utility		**Customers**			
	Earnings in $Billions[a]	ROE (25-Year Avg) (%)	Average Energy Bill ($/year)	Participant Energy Bill ($/year)	Non-participant Energy Bill ($/year)	Average Energy Rate (¢/kWh)
Utility with Residential EE Programs But No Business Model Features	45.84	11.18	2,484	2,343	2,533	19.22
Prototypical Business Model	46.88	11.43	2,511	2,367	2,560	19.42
Alternative Business Model 1	46.88	11.43	2,511	2,439	2,536	19.42[b]
Alternative Business Model 2	46.85	11.42	2,510	2,367	2,559	19.42

b. Benefit-Cost Tests[c]

($Milions)	Rate Impact Measue Test (RIM)	Total Resource Cost Test (TRC)	Program Administrator Cost Test (PAC)	Participant Cost Test (PCT)
Utility with Residential EE Programs But No Business Model Features	-312	146	161	307
Prototypical Business Model	-312	146	161	307
Alternative Business Model 1	-47	146	161	125
Alternative Business Model 2	-312	146	161	307

[a] Total cumulative earnings over 25 years, not discounted.

[b] Only a portion of this rate comes from volumetric charges, making the actual rate paid 9.55 ¢/kWh.

[c] Values reported for the benefit-cost tests are the net present values of the net benefits over 25 years with a 7% discount rate for the RIM, TRC, and PAC tests and 10% for the PCT.

To further illustrate the differences in energy cost distribution between the three business models, Figure 4 shows the increase in energy bills by customer participation status resulting from full implementation of each business model compared to a utiity operating the energy-efficiency program with no business model features. Again, it is clear that Alternative 1 places a much larger share of the cost of residential energy-efficiency programs on participating households than does either the prototypical business model or Alternative 2. The impact on the participants is large because there are so many fewer participants than customers. If more of the customers were able to participate in the programs then the participant energy cost would be closer to the average cost in Alternative 1.

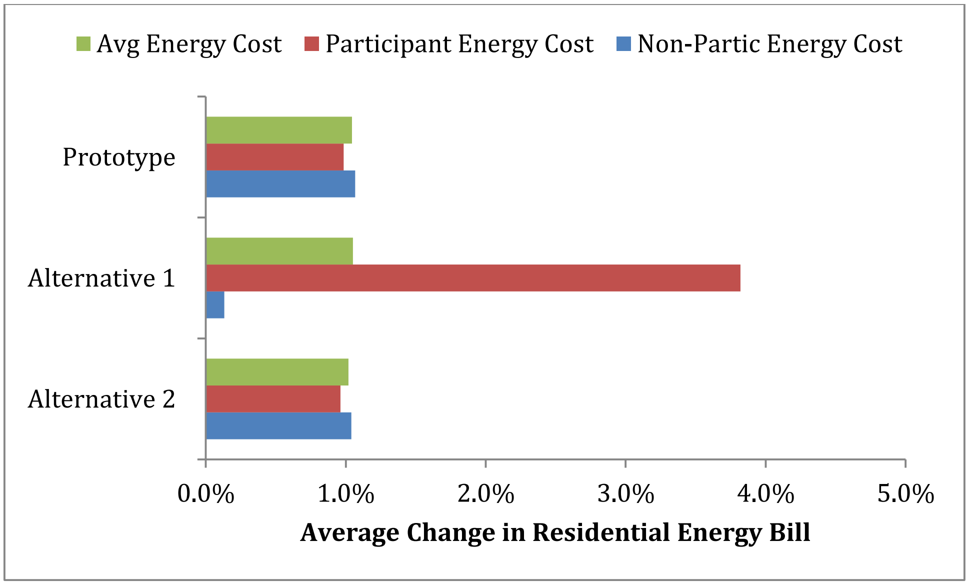

Figure 4: Impact of Business Models on Residential Utility Bills
(Note: Compared to an EE program without business model features)

Since debates over business models could be improved by focusing attention on the most impactful features of the business models, we examine the relative impacts on energy cost and utility earnings by business model and feature for the residential programs. Figure 5 illustrates the impacts of each business model on customer energy bills and utility earnings compared to an energy-efficiency program with no business model features. It is clear that the decoupling feature is the most impactful, regardless of whether LRAM, SFVR, or Per Customer Decoupling is used. Program costs represent about 15% of the impact of any of the business model alternatives, and performance incentives amount to less than 1% of total impact.

For reference, we include both the level of earnings authorized by the utility's ROE and the level of earnings achieved in the base case without any energy-efficiency program. The authorizedearnings is calculated based on the 11.15% return on the rate base calculated in each year while the base case is drawn from the base case scenario in the tool.

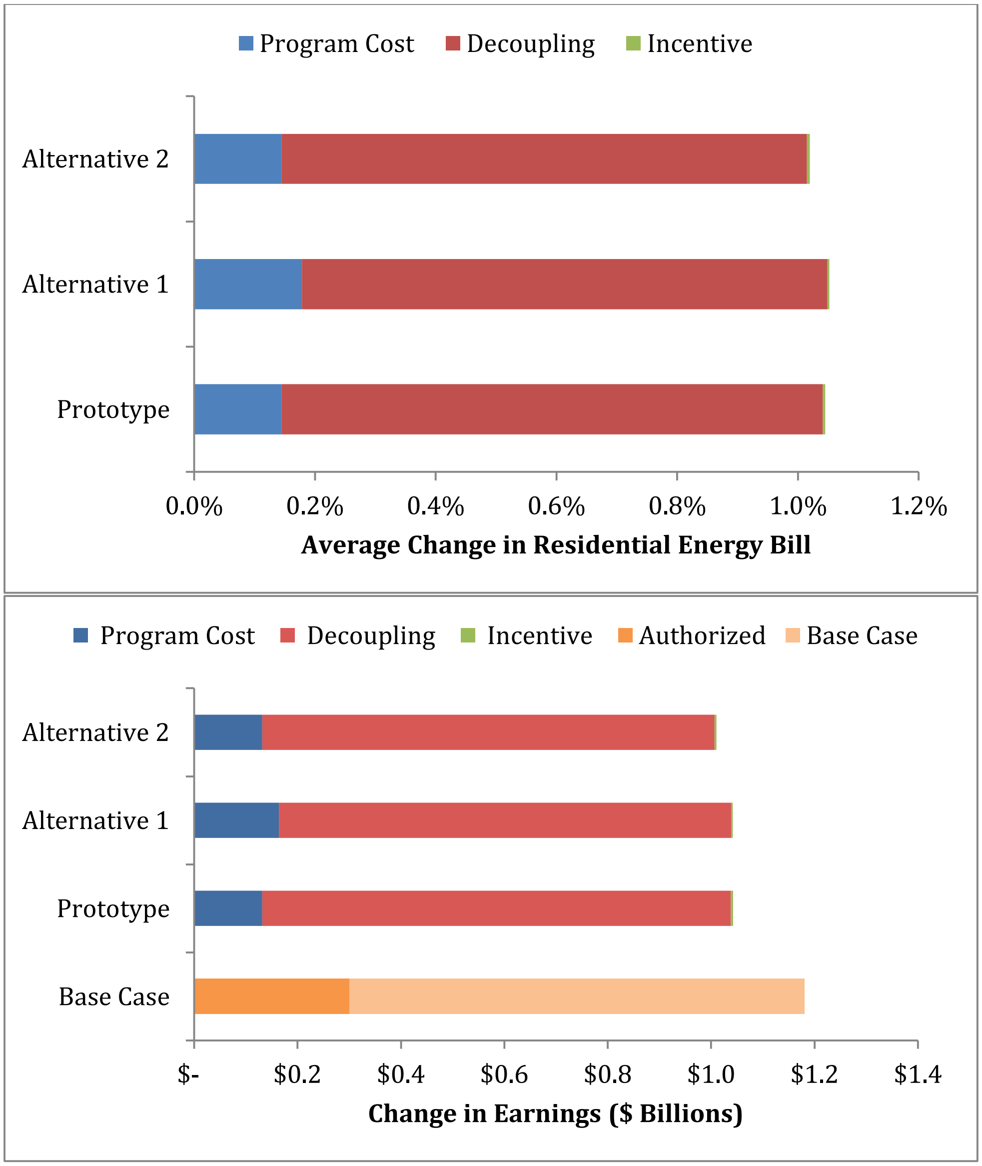

Figure 5. Impact of Business Models On Utility Earnings and Average Residential Utility Bills
(Note: Compared to an EE program without business model features; Base Case is the utility without EE programs)

5.3.2 The Prototypical Southeast Business Model's Impacts on Commercial Program Economics

As with the residential programs, in all of the business models evaluated, combining the three legs of the stool largely restores utilty earnings and ROE to the levels of the "base case." The cumulative loss in earnings of $1.8 billion from implementing the commercial programs is reduced to $0.2-0.3 billion. ROE rises to 11.39-11.41%, compared to the "base case" return of 11.46% and the authorized return of 11.25%.

Customer metrics for the commercial programs show greater impacts on bills but similar impacts on rates as for the residential programs (Table 7). Even after implementation of the business models, average bills are reduced almost 4% compared to the "base case." Average rates over 25 years increase about 1.07%. This represents a relatively modest increase in rates over the 25 years (see Figure 3).

Table 7. Impact of the Business Models on Commercial Program Economics

a. Utility and Customer Metrics

	Utility		**Customers**			
	Earnings in $Billions[a]	ROE (25-Year Avg) (%)	Average Energy Bill ($/year)	Participant Energy Bill ($/year)	Non-participant Energy Bill ($/year)	Average Energy Rate (¢/kWh)
Utility with Commercial EE Programs But No Business Model Features	45.22	11.04	26,747	22,293	28,070	12.35
Prototypical Business Model	46.79	11.41	27,015	22,516	28,351	12.50
Alternative Business Model 1	46.70	11.39	27,004	23,373	28,096	12.50[b]
Alternative Business Model 2	46.75	11.41	27,014	22,516	28,351	12.50

b. Benefit-Cost Tests[c]

($Millions)	Rate Impact Measue Test (RIM)	Total Resource Cost Test (TRC)	Program Administrator Cost Test (PAC)	Participant Cost Test (PCT)
Utility with Commercial EE Programs But No Business Model Features	-61	1,424	2,086	788
Prototypical Business Model	-61	1,424	2,086	788
Alternative Business Model 1	469	1,424	2,086	455
Alternative Business Model 2	-61	1,424	2,086	788

[a] Total cumulative earnings over 25 years, not discounted.

[b] Only a portion of this rate comes from volumetric charges, making the actual rate paid 9.54 ¢/kWh.

[c] Values reported for the benefit-cost tests are the net present values of the net benefits over 25 years with a 7% discount rate for the RIM, TRC, and PAC tests and 10% for the PCT.

In the case of commercial programs, the three business models again distribute the costs and benefits of energy efficiency between utilities, participants, and non-participants in different ways. All three models again recover utility earnings and ROE through increases in all customers' energy bills and rates. Alternative Model 1 again stands out due to its SFVR mechanism allocating a greater portion of the annual energy cost increases to participating customers than seen in the prototypical business model or Alternative 2. The benefit-cost test results for the three business models also show Alternative Model 1 decreasing the PCT net benefit while improving the RIM test score. However, the reduction in lost revenues from SFVR for commercial programs is so large that the RIM test score for Alternative Model 1 becomes positive, making all four cost test results positive.

To further illustrate the differences in energy cost distribution between the three business models, Figure 6 shows the increase in energy bills by customer category for each business model as compared to an energy-efficiency program with no business model features. Again, it is clear that Alternative Model 1 places a much larger share of the cost of implementing the business models for commercial energy-efficiency programs on participating customers than does either the prototypical business model or Alternative Model 2. As with the residential programs, the impact on the participants is large because there are so many fewer participants than customers. If more of the customers were able to participate in the programs then the participant energy cost would be closer to the average cost in Alternative 1.

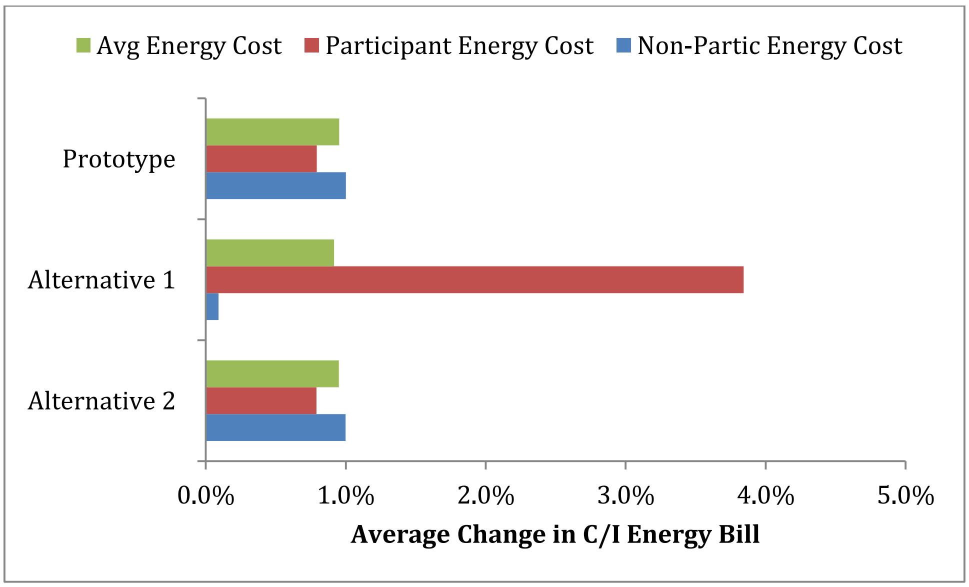

Figure 6. Impact of Business Models On Commercial Utility Bills
(Note: Compared to an EE program without business model features)

We again examine the relative impacts on energy cost and utility earnings by business model and feature for the commercial programs. Figure 7 illustrates the impacts of each business model on customer energy cost and utility earnings compared to an energy-efficiency program with no business model features. As noted before, the decoupling feature is the most impactful, regardless of whether LRAM, SFVR, or Per-Customer Decoupling is used. Relative to residential programs, however, commercial program business models exhibit a smaller share of impact for program costs and a greater share of impact for the the incentive amount.

For reference, we include both the level of earnings authorized by the utility's ROE and the level of earnings achieved in the base case without any energy-efficiency program. The authorized earning is calculated based on the 11.15% return on the rate base calculated in each year, while the base case is drawn from the base case scenario in the tool.

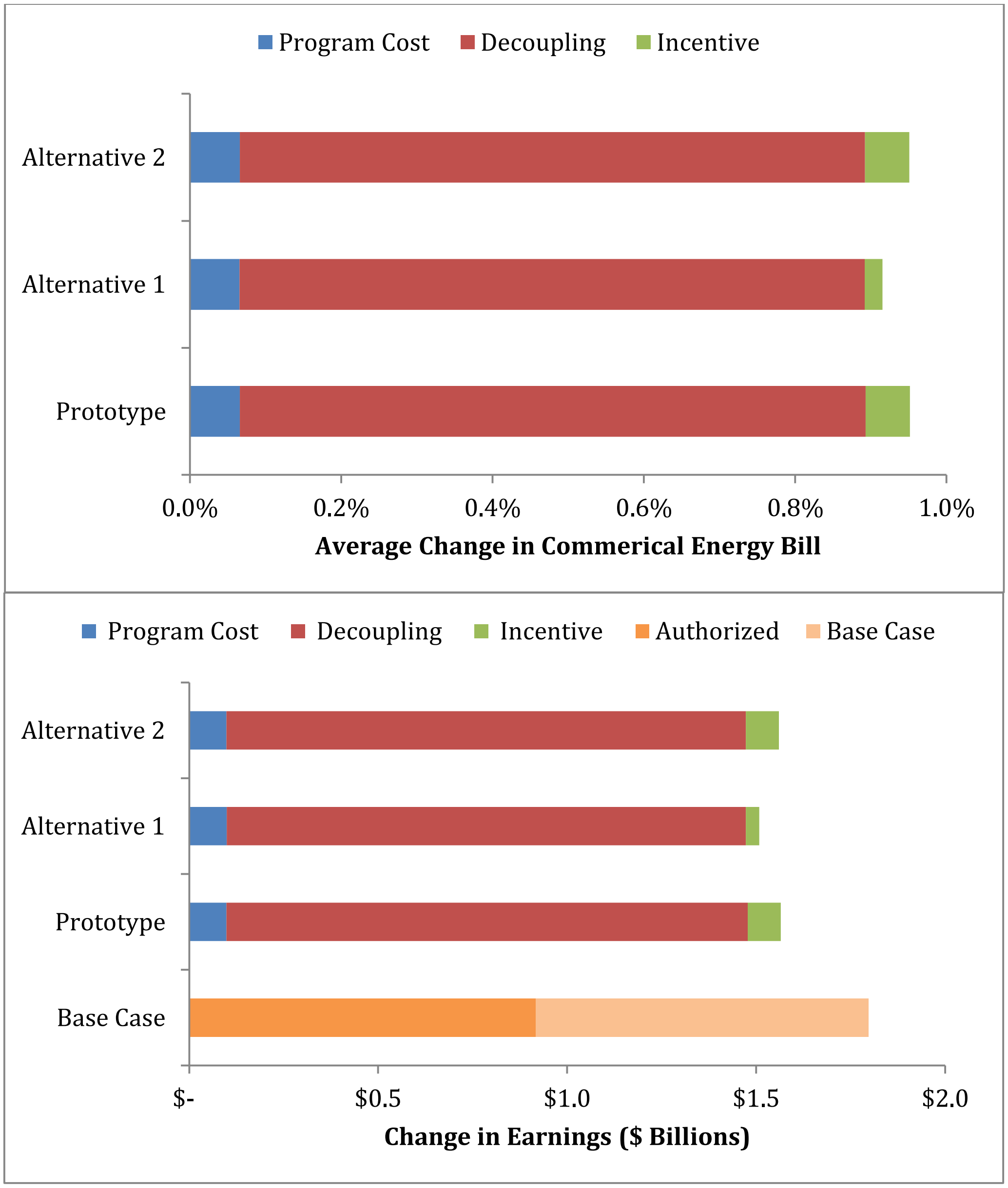

Figure 7. Impact of Business Models On Utility Earnings and Average Commercial Utility Bills
(Note: Compared to an EE program without business model features; Base Case is the utility without EE programs)

6. CONCLUSIONS

Our study contributes to the lively national debate about the pros and cons of rate-of-return regulation that dominates the electricity industry in the Southeast. How does this traditional regulatory approach compare to the alternative business models that compensate or incentivize utilities for investing in distributed energy resources such as energy efficiency, solar energy, demand-response resources, and energy storage?

We focus on creating a fact-based and replicable set of answers to this question by characterizing and then evaluating the business model for energy efficiency that is emerging in the Southeast. Following a review of the literature, case studies of four southeastern states and Massachusetts, and expert consultations, we identify eight business model features to examine, including: two ways that utilities can recover program costs, three ways of recovering lost contributions to fixed costs, and three ways of providing a performance incentive to the utility. In addition, we define a prototypical southeastern business model with the most common of these features: expensing program costs, using the lost revenue adjustment mechanism (LRAM), and rewarding performance with shared savings based on net benefits from the Program Administrator Cost (PAC) test.

We quantitatively analyze the impacts of these features on utility and customer economics using a prototypical southeastern investor-owned utility that operates a mid-range energy-efficiency portfolio of programs. These programs spend about 0.5% of utility revenues annually to save about 0.4% of sales. The energy-efficiency programs last for 10 years, and their impacts are assessed over 25 years, reflecting the 10-15 year lifetime of measures.

When these programs are implemented in the absence of any business model features, the portfolio has positive scores on the TRC, PAC and PCT tests, but a negative score on the RIM test. The RIM test indicates a benefit to participating customers, however, as well as an opportunity to share that benefit with the utility through an energy-efficiency business model. Despite the RIM score, implementation of the portfolio reduces average rates over the 25 years. This downward pressure on rates is attributed to a “DRIPE” effect.

When each leg of the business model is applied alone:

- Amortizing program costs over three years produces a slightly greater return for the utility and slightly higher utility bills for the customer, compared with expensing program costs. The “DRIPE” effect reduces average rates even after the recovery of program costs.

- All three decoupling features result in an average rate increase of about 0.9%. Non-participants pay more with the LRAM than a SFVC mechanism because the LRAM spreads lost revenues across all customers, rather than creating a fixed cost adjustment driven by a volumetric increase in bills.

- Providing program incentives based on net benefits from the PAC test produces more earnings and ROE for the utility compared with the other two incentive mechanisms. All three incentive features produce impacts somewhat less than program costs.

None of the features, when considered independently, delivers the earnings and ROE of the utility without the energy-efficiency programs. Even if the utility recovers program costs and the PAC incentive, there is still downward pressure on average rates over the 25-year horizon because of the “DRIPE” effect. With this combination, the utility is still left well short of the earnings and ROE it would have received without the energy-efficiency programs (11.46%). The utility is also left short of its authorized ROE of 11.25%. The customers as a whole benefit from reductions in average bills, and the reduction for participants in the programs is quite significant.

The features for decoupling utility profits from energy sales have the largest impact on our metrics, much more than the other two legs of the business model. These features, therefore, deserve particular focus in discussions of the business model. While the LRAM, based on a rider with annual true-up, is emerging as the norm in the Southeast, the debate on best practice is far from over, as suggested by our 4 southeastern case studies. After using LRAM for 3 years, the Arkansas PSC has invited utilities to propose more fully decoupled mechanisms. The Virginia SCC has raised questions about the proof of lost revenues and has yet to approve a request for recovery in a rider proceeding. In North Carolina, recovery is limited to three years. Where this approach is adopted, rate increases from the LRAM would be less than from the approach modeled in this paper. In Georgia, lost revenues needed to cover fixed costs are still recovered in rate cases.

Combining features into the prototypical southeastern business model significantly reduces the loss in utility earnings that would otherwise accompany the implementation of energy-efficiency programs. The loss of approximately $3 billion for a utility without any business model features shrinks by $2.7 billion ($1.1 billion in the residential sector and $1.6 billion in the commercial setor). The prototypical business model also produces the largest increase in return on equity. The utility's ROE still falls slightly short of the 11.46% rate it would enjoy without implementing the energy-efficiency programs, but it exceeds the authorized rate of 11.25%. With the prototypical business model, average bills overall, as well as participant bills, are reduced, but the bills of non-participants would rise slightly. Average rates would increase 1% over 25 years.

In addition to showing that the implementation of energy-efficiency programs in conjunction with business model features would likely have modest impacts on average overall bills and rates, we have shown that the choice of business model can have significant repercussions for the utiity's earnings and profits. All approaches provide participants with lower bills but non-particpant bill changes depend on the approach chosen. Business models can distribute costs across participants and non-participants equally or can allocate them primarily to participants, as is the case with the SFVR feature. The wide range of possible treatments of costs and benefits underscores the importance of selecting the business model with the best overall impacts given the goals of the policymakers. This choice will be increasingly important in the future if energy-efficiency programs grow in scope and scale as anticipated by many.

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Appendix A

Table A-1. Linking GT-DSM Components to Standard Benefit-Cost Tests

Component	Rate Impact Measure	Total Resource Cost	Program Administrator Cost	Participant Cost Test
Electric avoided costs	Benefit	Benefit	Benefit	
Additional resource savings		Benefit		
Incremental measure costs		Cost		Cost
Program administrative costs	Cost	Cost	Cost	
Incentive costs	Cost		Cost	Benefit
Bill savings	Cost			Benefit

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